PRELIMINARY DETERMINATION AND STATEMENT OF BASIS
ON THE APPLICATION OF

DUKE ENERGY MARSHALL COUNTY, LLC.'s
MARSHALL COUNTY GENERATING STATION

TO CONSTRUCT AND OPERATE A GAS-FIRED SIMPLE CYCLE COMBUSTION
TURBINE PEAKING STATION FOR ELECTRICITY PRODUCTION
TO BE LOCATED NEAR CALVERT CITY, KENTUCKY

REVIEW AND ANALYSIS BY:
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1. EXECUTIVE SUMMARY

Duke Energy Marshall County, LLC submitted a permit application dated December 9, 1999 to construct and operate a natural gas fired, peaking station for electricity generation in Marshall County, Kentucky. The Marshall County Generating Station, is to include eight (8) General Electric 7EA natural gas-fired combustion turbines which are to operate in simple cycle mode with a nominal output capacity of 80 megawatts (MW) each. Each turbine is to be equipped with its own exhaust stack. The proposed facility is to increase peak power supply and help alleviate peak power shortages and curtailments, which have significantly impacted existing and proposed industry. The facility is to produce electricity during periods of peak electricity demand on a daily and seasonal basis. The power plant will have a nominal electric generating capacity of 640 megawatts (MW). The plant is to be limited to operating 2500 hours per year or less for each unit. The proposed plant will be a major source as defined in Kentucky State Regulation 401 KAR 51:017 (40 CFR 52.21), Prevention of Significant Deterioration (PSD) of air quality, with emissions of nitrogen oxides (NO_x) and carbon monoxide (CO) regulated air pollutants in excess of 250 tons per year. Pursuant to Kentucky State Regulation 401 KAR 50:035, Permits, the source is required to obtain a federally-enforceable permit to construct and operate the proposed plant.

The plant does not belong to one of the 28 major source categories listed because the gas turbines will be used without heat recovery. Therfore, simple cycle peaking units, have been determined to fall outside of the 28-source category list. The potential emissions of nitrogen oxides (NO_x) and carbon monoxide (CO) from this plant are more than 250 tons per year, and potential emissions of sulfur dioxide (SO_2), (PM), and particulate-10 (PM-10) are in excess of the significant net emission rates as presented in Regulation 401 KAR 51:017, Section 22. The source will be located in a county classified as “attainment” or “unclassified” for each of these pollutants pursuant to Regulation 401 KAR 51:010, Attainment status designations. Consequently, the proposed facility meets the definition of a major stationary source and is subject to evaluation and review under the provisions of the PSD regulation for all these pollutants. A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under Title 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40CFR 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

Additionally, this source is subject to Title V and Title IV Phase II Acid Rain permitting, as well as, PSD permitting. The Title V permitting procedures are within State Regulation 401 KAR 50:035, Permits and Federal Regulation, 40 CFR Part 70. The Title IV permitting procedures are within State Regulation 401 KAR 50:035, Permits, 401 KAR 50:072, Acid Rain Permit, and Federal Regulation 40 CFR part 76. Therefore, this proposal represents the draft PSD/Title V permit and the draft Title IV Phase II Acid Rain permit. The preliminary determination is also provided as a statement of basis for the Title V permit. This review demonstrates that all regulatory requirements will be met and includes a draft permit which establishes the enforceability of all applicable requirements.

2. BACKGROUND

On December 9, 1999, the Division received a permit application to construct and operate a natural gas-fired simple cycle turbine peaking station for electricity generation from Duke Energy Marshall County Generating, LLC.

Additional information was requested on numerous occasions and responses received on the following dates:

Information Requested	Date Requested	Information Received	Date Received
Email Request	January 14, 2000	Email Response	January 18, 2000 January 19, 2000
		Additional BACT info	February 3, 2000
Deficiency Letter	February 3, 2000	Response Email Written Response Formaldehyde Emission Factors Additional BACT info	February 10, 2000 February 16, 2000 February 23, 2000 March 2, 2000 March 23, 2000

The application was logged complete on March 27, 2000.

Information from the application is given and assumed.

3. EMISSIONS ANALYSIS

The proposed Marshall County Generating Station will produce electricity during periods of peak demand. The electricity generation operations will consist of: eight (8) natural gas-fired simple cycle combustion turbines (nominally 80 MW each) equipped with low NOx burners and inlet fogging, an emergency fire-water pump engine (to operate 500 hours or less per year in emergencies) that is diesel-fired and four (4) fuel oil storage tanks. For a detailed description of the plant processes and expected emissions at each emissions point and emissions unit, please see Section 2, Section 3, and Appendix B of the application. Please reference the application for the hourly and annual emission rates and pollutant identification for each respective emissions unit. Emissions were based on the maximum rated capacity of the plant, worst case operating conditions, and 2500 hours per year of operating time for each turbine after controls (oil firing with water injection is allowed for up to 500 of the operating hours. The turbines' annual emissions in Table 3-1 of the application are calculated for ambient temperature of 57 degrees Fahrenheit and baseload conditions (rated capacity output) utilizing fuels projecting worst case operating conditions.

4. REGULATORY REVIEW

This section presents a discussion on the air quality regulations applicable to this project. In some cases the emission limit or technology standard based on these regulations may be superseded by the BACT requirements which are more stringent under PSD (see Section 5, Best Available Control Technology Review); however, any specific testing, monitoring, record keeping, and reporting requirements contained in these regulations will still have to be met by the source in addition to any requirements under PSD.

The following regulations will apply to the proposed plant (please see the application for a detailed description of the plant and specific processes/units within the plant):

Regulation 401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, for emissions units with a heat input at peak load equal to or greater than 10 MMBTU/hour for which construction commences after October 3, 1977, applies to each of the simple cycle gas-fired turbines. The proposed BACT is much less than the applicable standard for nitrogen oxides emissions in Subpart GG, with an hourly limit of 12 ppm by volume corrected to 15 percent oxygen on a dry basis and an annual limit of 9 ppm by volume corrected to 15 percent oxygen on a dry basis while firing natural gas, and 42 ppm by volume corrected to 15 percent oxygen on a dry basis while firing low sulfur diesel fuel.

Subpart GG standard for sulfur dioxide is that no owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight. Proposed BACT for sulfur dioxide is consistent with the EPA RACT/BACT/LAER Clearinghouse for gas turbines which is firing natural gas that contains less than 2.0 grains/100 SCF of sulfur and diesel fuel with a sulfur content equal to or less than 0.05% weight percent.

Subpart GG requires that the owner or operator using water injection (the proposed BACT to control nitrogen oxides emissions will firing diesel fuel) shall install and operate a continuous monitoring system to monitor and record fuel consumption and the ratio of water to fuel being fired in the turbine. Periods of excess emissions that must be reported are defined in 40 CFR 60.334(c). The permit provides the appropriate monitoring, testing, reporting, and record keeping requirement of Subpart GG. Nitrogen oxides continuous emission monitors (CEMs) are to be used in lieu of monitoring the water to fuel ratio.

In accordance with 40 CFR 60.334 to meet the requirement for fuel sulfur content testing, the following alternative fuel-monitoring schedule has been approved;

i) The Permittee will sample the natural gas for sulfur content every six months, except when firing pipeline quality natural gas the sulfur content is assumed to be in compliance and testing is not required.
ii) The permittee will sample the diesel fuel in accordance with 40 CFR 75, Appendix D.

A performance test is required by Subpart GG for nitrogen oxides, and oxygen concentrations, and sulfur content. Please refer to 40 CFR 60.335 for further testing details. The permittee will have a continuous emission monitor (CEMs) for carbon monoxide as well.

Acid Rain regulations, 40 CFR 72 through 40 CFR 78 apply. This source is required to apply for a Phase II Acid Rain permit. Part 75 requires continuous emission monitoring.

Regulation 401 KAR 51:017 (40 CFR 52.21), Prevention of significant deterioration of air quality, applies to the proposed plant which will be located in Marshall County currently designated as "attainment" or "unclassified" for all ambient quality standards. The proposed plant has the potential to emit more than 250 tons per year of one or more regulated criteria pollutants.

Total plant wide potential emissions of all criteria pollutants including fugitive emissions are:

Pollutant	**PTE * (tons per year)**	**Significant Emission Rate ** (tons per year)**
Nitrogen oxides (NO_x)	655.9	40
Carbon monoxide (CO)	538.9	100
Sulfur dioxide (SO_2)	160	40
Particulate (PM)	134	25
Particulate matter (PM_{10})	134	15
Volatile organic compounds (VOC)	38.6	40
Mercury (Hg)	0.002	0.01
Beryllium (Br)	0.0008	0.0004
Sulfuric Acid Mist (H2SO4)	18.7	7
Arsenic (As)	0.01	>0
Benzene	NA	>0
Lead (Pb)	0.14	0.6

* PTE - Potential to emit, emissions for turbines calculated with 2500 hours/year operation and worst case operating conditions, and include ancillary equipment.
** Significant emission rate as given in Regulation 401 KAR 51:017, Section 22.

As seen in the table above, the plant will be a major source for nitrogen oxides and carbon monoxide. The PSD review applies to every pollutant that the proposed plant will emit in significant quantities, i.e., in amounts that will exceed the respective significant net emission rate. As seen above, the plant will be subject to PSD review for nitrogen oxides, carbon monoxide, sulfur dioxide, particulate and particulate-10. For each of these pollutants, the applicant will have to perform a best available control technology (BACT) demonstration and an ambient air quality analysis. Each of these components of the PSD review process have been discussed in detail in the following sections.

5. BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

Pursuant to Regulation 401 KAR 51:017, Section 9(1) and (2), a major stationary source subject to a PSD review shall meet the following requirements,

(a) The proposed source shall apply the best available control technology (BACT) for each pollutant that it will have the potential to emit in significant amounts.

(b) The proposed source shall meet each applicable emissions limitation under Title 401, KAR 50 to 65, and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63.

The proposed source will be a major source resulting in emissions of nitrogen oxides, carbon monoxide, sulfur dioxide, particulate, and particulate-10 that exceed the corresponding PSD net significant emission amounts. Therefore, each of these pollutants shall be subject to a BACT review.

Duke Energy Marshall County, LLC has presented, in the permit application, a study of the best available control technology for each pollutant and each emissions unit at the proposed source. The Division has reviewed the proposed control technology in conjunction with information available in the U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and by U.S. EPA Region IV. A summary of the control technology determined to be the best available control technology for each pollutant and each emissions unit is presented on the following pages:

A. Simple Cycle Gas Combustion Turbines

EIS No.	Emissions Unit/Process	Pollutant	Best Available Control Technology	Emission Standard
01, 02, 03, 04, 05, 06, 07, and 08 (CT-1, CT-2, CT-3, CT-4, CT-5, CT-6, CT-7, and CT-8)	Gas Turbines Operation limitation per turbine: 2500hour/year or less 500 hour/year or less when using diesel fuel	NO_X Natural Gas	Dry low NO_X Burners	Hourly Limit: 12 ppm by volume at 15 % oxygen and on a dry basis Annual Limit: 9 ppm by volume at 15 % oxygen and on a dry basis
		NO_X Diesel Fuel	Low NO_X burners with water injection and good combustion practices	42 ppm by volume at 15 % oxygen and on a dry basis
		CO Natural Gas	Good combustion control	25 ppmvd at 15 % oxygen for operation at rated capacity output
		CO Diesel Fuel	Good combustion control	20 ppmvd at 15 % oxygen
		SO_2 Natural Gas	Low sulfur natural gas fuel	2.0 grains/100 SCF
		SO_2 Diesel Fuel	Low Sulfur Diesel	0.05 wt. % sulfur in fuel
		PM/PM_{10} Natural Gas	Low ash fuel and good combustion control	10 lbs/hr/turbine
		PM/PM_{10} Diesel Fuel	Low ash fuel and good combustion control	26 lbs/hr/turbine

B. Diesel Emergency Fire-Water Pump/Engine

EIS No.	Emissions Unit/Process	Pollutant	Best Available Control Technology	Emission Standard
(--)	Diesel Emergency Fire-Water Pump/Engine Operation limitation: 500 hours of operation per year.	NO_x	Good combustion control/ Good operating practices	6.60 lbs/hour
		CO	Good combustion control	1.80 lbs/hour
		SO_2	Use of low sulfur fuel / Good combustion control	0.05 wt. % sulfur in fuel/ 0.13 lbs/hour
		PM/PM_{10}	Use of low ash fuel/Use of low sulfur transportation diesel fuel/ Good combustion control	1.10 lbs/hour

The permittee submitted a top-down Best Available Control Technology (BACT) analysis following the U.S. EPA guidance, "New Source Review Workshop Manual" (U.S. EPA, October 1990). The key steps involved with the top-down BACT process are as follows:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate most effective controls considering economic, environmental, and energy impacts, and document results
5. Select BACT.

A. BACT for Simple Cycle Natural Gas-Fired Combustion Turbines

This project is being proposed as a simple cycle electrical peaking facility. A simple cycle peaking project is fundamentally different than "combined cycle" baseload power supply systems that represent the majority of listings in the EPA RACT/BACT/LAER Clearinghouse.

Basically, once base load power demands are met, a need still exists to supply additional power at certain times when base load requirements are exceeded by a short term peak power demand. This simple cycle electrical peaking facility configuration meets this short term power supply need. These simple cycle gas-fired combustion turbines must therefore be able to come on-line and supply this power quickly which involves a rapid, quick start-up period.

Thermal stress from this rapid start-up process subjects certain materials, such as metals and ceramics, to differential thermal expansion and will cause stress that with cycling may result in failure of equipment if enough time is not taken to bring the temperature up gradually. On a given day, the demand for peak power may be short requiring quick startup.

This rapid start-up sequence for a peaking plant results in difficulties with applying various control technologies to this project. A distinction must be made between previous BACT decisions for combined cycle units and simple cycle units due to the differing nature of operation and lower exhaust temperatures associated with combined cycle applications. A detailed discussion of the BACT determination submitted by Duke Energy is located in Section 5 of the permit application. Following is a summary of the Control Methods examined and final controls approved as BACT.

NO_x

Nitrogen oxides are primarily formed in combustion processes in two ways: (1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal nitrogen oxides), and (2) the oxidation of nitrogen contained in the fuel (fuel nitrogen oxides). Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen (EPA 1996); therefore, nitrogen oxides emissions from combustion turbines originate as thermal nitrogen oxides. The rate of formation of thermal nitrogen oxides is a function of residence time and free oxygen, and is exponential with peak flame temperature.

Duke Energy Marshall County, LLC proposes to implement nitrogen oxides BACT, while firing natural gas, through the use of GE Frame 7EA Turbines. GE has, over the years, produced engines that are more efficient and at the same time are capable of achieving lower nitrogen oxide (NO_X) emissions. These units are therefore built with dry low-NO_X burners which achieve a maximum emission rate of 15 parts per million on a dry volume basis (ppmvd). GE has stated that these devices, when properly operated and maintained, can achieve an emission rate as low as 9 ppmvd without add-on control devices during steady state operations. GE defines steady state as follows:

> Steady state is defined as the condition of the turbine where the roto is in thermal equilibrium and the load on the unit is not changing by greater than 0.5%. Rotor thermal equilibrium is defined as less than a 5 degree Fahrenheit change in the wheel spacing in any 15 minute interval. The unit load change is defined as greater than a 0.5% change in the kW output, or more than a 0.5% change in the fuel flow of the unit within 2 minutes prior to sampling and one minute after sampling.

Duke Energy has raised concerns that a short-term emission limit of 9 ppmvd may not be possible with the frequent startups and shutdowns that these machines are expected to experience. In addition, monitoring parameters are not readily available to satisfactorily verify steady state operation of peaking units. The division agrees that requiring a short-term limit of 9 ppmvd is not feasible, and has determined that an hourly average of 12 ppmvd corrected to 15 % oxygen, while firing natural gas, will be achievable. In addition, to satisfy the requirement to reduce overall emissions a reduced annual (12-month rolling average) limit of 9 ppmvd at 15% oxygen, while firing natural gas, has also been determined to be attainable. The permittee also agrees to limit emissions while firing low sulfur diesel fuel by using water injection and achieving an hourly average of 42 ppmvd at 15% oxygen. In addition, to further limit emissions annually the permittee agrees to limit operating hours of each unit to 2500 hours per year and limit diesel fuel firing to 500 hours or less per unit.

Other control technologies were evaluated and more detailed determinations are located on pages 5-1 through 5-13 of the permit application. SCR was eliminated as a control alternative due to economic and environmental impacts and possible performance problems associated with the high exhaust temperatures of the simple cycle turbines. Catalytic combustion is currently not available for the size and operating parameters necessary for the proposed project and therefore eliminated as a possible NOx control alternative for BACT. Based on the data available and alternate control methods the division agrees that the use of ultra low NOx burners and low sulfur diesel fuel with water injection represent the Best Achievable Control Technology for the proposed simple cycle turbine project. The division agrees with the proposed NOx limits, of 9 ppm annually and 12 ppm hourly, while burning natural gas and 42ppm while burning oil, which are much lower than the 15 ppm hourly limits that are currently being permitted for similar projects, and equivalent to the limits for an identical project currently drafted in Missouri.

CO

Carbon monoxide is formed as a result of incomplete combustion of fuel. For carbon monoxide control, the permittee evaluated the available control technologies which are: high temperature catalytic oxidation and the front-end technique of good combustion control. The most stringent CO control level available for simple cycle gas turbines would be achieved with the use of a high temperature (zeolite based) oxidation catalyst system, which can remove approximately 80 percent of CO in the flue gas (Booth, 1998, Section 5.4.2.1).

The Division has reviewed the EPA BACT/RACT/LAER Clearinghouse for combustion turbines.

Only approximately five cases since early 1990 are documented in the clearinghouse to have specified catalytic oxidation as BACT. The overwhelming majority of determinations specify good combustion practices/good combustion control and operation/proper design and in some cases no controls.

There are environmental impacts associated with the use of a catalytic oxidation system on a simple-cycle turbine due to the oxidation of SO_2 to SO_3. The SO3 can react with water or ambient ammonia in the exhaust and form sulfuric acid or ammonia sulfates. There is also generation of hazardous waste from the spent catalyst.

The economic analyses provided for the CO oxidation catalyst are shown in Appendix D of the permit application. The Division has reviewed and accepted cost data provided by the applicant. This information indicates the total capital investment costs, annualized costs, and overall cost effectiveness for CO emissions calculated by the permittee. The following table 2 summarizes the results of the overall cost effectiveness of CO removal for each turbine:

Table 2

Turbine Model	**Overall Cost Effectiveness ($/ton)**
GE 7EA Turbine	6,200

- The annualized cost is taken from the application, Appendix D and reflects the limited hours of operation. The tons per year controlled of carbon monoxide is determined from the 67.3 TPY per unit potential, with 90% control efficiency by catalytic oxidation.

The Division has determined that the overall cost effectiveness numbers indicate that the application of high temperature catalytic oxidation for CO is not economically feasible.

Considering the potential environmental and energy impacts associated with extended startup times and the economic impact of oxidation catalyst technology, the Division agrees with the permittee's elimination of this control technology.

The next most stringent level of control for CO is efficient combustion control. The advanced low NOx combustors of the GE 7EA turbines maintain low CO emission rates at operating loads above 60 percent unlike other combustion units which typically have increased CO emissions below 70 percent load. CO emissions will be limited to 25 ppmvd at 15% oxygen and 20 ppmvd at 15% oxygen when firing natural gas and diesel fuel, respectively. This level of control is documented as available and that it will not cause negative environmental impacts or operational impacts. This type of control is the most common in the BACT/LAER clearinghouse. Therefore, the division agrees that good combustion control as proposed is BACT for CO emissions.

$\underline{SO_2}$

Sulfur dioxide is formed exclusively from the oxidation of the sulfur present in the natural gas fuel. The emission rate is a function of the sulfur content of the fuel since virtually all the sulfur in the fuel is converted to SO_2. Therefore, utilization of low sulfur fuels is the simplest means for limiting SO_2 emissions. Additional control alternatives include add-on controls such as flue gas desulfurization (FGD) systems.

The permittee has agreed to limit SO_2 emissions by firing natural gas and low sulfur diesel fuel. FGD systems are not typically effective for streams with low SO2 concentrations, such as those that would result from firing the proposed fuels. In addition, FGD typically operate at temperatures in the range of 400 to 500 °F the exhaust from the proposed turbines will be in the 1000 °F range. This high exhaust temperature would require conditioning before it could be treated by an FGD.

The Division has reviewed the EPA BACT/RACT/LAER clearinghouse and natural gas/low sulfur fuel is the main control technique used for reducing SO_2 emissions. One case documented engine design and use of natural gas as fuel. The applicant's review indicates use of low sulfur fuel as the only available SO_2 control method to be selected as BACT in previous determinations for gas turbines.

This indicates that firing of natural gas and low sulfur diesel fuel is the most stringent SO_2 control technique that has been demonstrated to be feasible for simple cycle gas turbine applications. Therefore, the Division agrees with the permittee's BACT determination for SO_2, which is use of low sulfur fuel/natural gas and low sulfur diesel fuel with a sulfur content less than or equal to 0.05%. Additionally, operation of the turbines using low sulfur diesel fuel will be limited to no more than 500 hours per year.

<u>PM/PM_{10}</u>

Particulate emissions from natural gas combustion consist of inert contaminants in natural gas, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, particulate of carbon and hydrocarbons resulting from incomplete combustion, mineral matter in the water injected during diesel fuel firing, and condensable. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions. Trace metals may be emitted from natural gas combustion and are discussed in this section because these form a part of the particulate emissions. The Division has checked the lead emissions based on an AP-42 factor and these are calculated at less than the net significant emission rate.

When the New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA recognized that "particulate emissions from stationary gas turbines are minimal." EPA noted that particulate control devices are not typically installed on gas turbines and that the cost of installing these is prohibitive (U.S. EPA September 1977). Performance standards for particulate control of stationary gas turbines were, thus, not proposed or promulgated.

The Division has reviewed the EPA BACT/RACT/LAER clearinghouse for gas turbines for particulate control BACT determinations. The Division has found the specification of natural gas as fuel to be the main control technique for particulates. Several listings specify BACT as low sulfur fuel, natural gas as fuel, maintaining the turbines in good working order, good combustion practice and operation, clean burning fuels, and no controls.

Therefore, as the permittee also explains on p. 5-16 to 5-17 of the application, the use of natural gas and low sulfur diesel fuel and good combustion control is concluded to represent BACT for particulate emissions from the simple cycle gas-fired combustion turbines. This amounts to a specification of 10.0 lbs/hour/turbine particulate emission limitation while firing natural gas and 26.0 lbs/hour/turbine while firing diesel fuel. Additionally, the division acknowledges that if the NOx and sulfur limits are met that the combustion control is sufficient to adequately control particulate emissions.

Control of Non-Criteria Pollutants

The combustion of natural gas and diesel fuel may release trace amounts of a number of non-criteria pollutants. Three of the PSD regulated pollutants (arsenic, beryllium, and sulfuric acid mist) require BACT analysis as defined by EPA. EPA has not yet finalized emission factors for benzene and has not yet established significance values for arsenic or benzene. As a result, the regulations require that for any potential emission above zero a BACT analysis be performed for these pollutants.

For all three pollutants the best available control technology is fuel substitution and combustion control. Natural gas and low sulfur diesel fuel contain significantly less ash and metal than coal or residual oil and are therefore considered suitable alternative fuels. Therefore, firing natural gas and low sulfur diesel fuel is considered BACT for arsenic and beryllium).

Additionally, the use of natural gas and limited use, 500 hours or less per year, of low sulfur diesel fuel is considered BACT for sulfuric acid mist.

B. Diesel Emergency Fire-Water Pump/Engine

The permittee has submitted modeling analysis of the ambient impact predicted to occur due to the diesel fire-water engine. The permittee has indicated that this engine will only operate for 500 hours or less in a year. Because the ambient impact was shown to be less than the significant impact levels, for this engine at this limited operation, this operational limitation has been included in the permit. This limitation is required to ensure the air quality impact is below the significant impact level. A full impact analysis will be required to increase this limit. This limit is thus included as part of the BACT analysis of emission levels.

NO_x

The permittee documents that EPA's draft Alternative Control Technology (ACT) document for reciprocating engines (EPA, 1996) lists add-on techniques such as SCR as well as combustion control techniques such as ignition retard for NO_x control from diesel engines. The ACT concludes that add-on controls are not cost effective for "emergency diesel engines" that typically operate less than 500 hours/year. The Division has accepted the permittee's proposal of good combustion control/good operating practices to be BACT for NO_x with the operational restriction of 500 hours per year.

CO

Add-on controls for CO emissions have never been applied to emergency diesel engines that operate less than 500 hours/year. The Division has therefore accepted good combustion control to represent BACT for the proposal, with the operational restriction of 500 hours per year.

SO_2

The permittee maintains that the only control technique available for diesel engines that operate less than 500 hours/year is the use of low sulfur fuel. The use of low sulfur diesel fuel, 0.05 wt. % sulfur, thus represents BACT for SO_2, with the operational restriction of 500 hours per year.

PM/PM_{10}

The most stringent particulate control method for a diesel engine that operates 500 hours/year or less is the use of a low ash fuel/low sulfur transportation diesel fuel. Therefore, the Division has accepted the use of a low ash low sulfur fuel with good combustion control to be BACT for PM/PM_{10}, with the operational restriction of 500 hours per year.

6. AIR QUALITY IMPACT ANALYSIS

Pursuant to Regulation 401 KAR 51:017, Section 12, an application for a PSD permit shall contain an analysis of ambient air quality impacts in the area that the proposed facility will affect for each pollutant that it will have the potential to emit in significant amounts as defined in Section 22 of the same regulation. The purpose of this analysis shall be to demonstrate that allowable emissions from the proposed source will not cause or contribute to air pollution in violation of:

(1) A national ambient air quality standard in an air quality control region; or
(2) An applicable maximum allowable increase over the baseline concentration in an area.

For pollutants for which no ambient air quality standard has been established, the analysis shall contain continuous air quality monitoring data gathered to determine if emissions of that pollutant will cause or contribute to a violation of the standard or a maximum allowable increase. The proposed facility will have potential emissions in excess of the significant net emission rates for nitrogen oxides, particulate/particulate-10, sulfur dioxide, and carbon monoxide.

A. Modeling Methodology

The application for the proposed source contains an air dispersion modeling analysis for criteria pollutants (nitrogen oxides, particulate/particulate-10, sulfur dioxide, and carbon monoxide) to determine the maximum ambient concentrations attributable to the proposed plant for each of these pollutants for comparison with:

1. The significant impact levels (SIL) found in 40 CFR 51.165 (b)(2).
2. The significant monitoring concentrations (SMC) found in Regulation 401 KAR 51:017, Section 24.
3. The PSD increments found in Regulation 401 KAR 51:017, Section 23.
4. The National Ambient Air Quality Standards (NAAQS) found in Regulation 401 KAR 53:010, Ambient air quality standards.

All the applicable air quality criterion are presented in Table 3. Based on the U.S. EPA suggested procedures, if the maximum predicted impacts for any pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling would be required for such a pollutant. The applicant may also be exempted from the ambient monitoring data requirements if the impacts are below the significant monitoring concentrations.

Table 3

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	SMC ($\mu g/m^3$)	PSD Class II Increments ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_x	Annual	1	14	25	100
PM_{10}	Annual 24-hour	1 5	NA 10	17 30	50 150
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	20 91 512	80 365 1300
CO	8-hour 1-hour	500 2000	575 NA	NA NA	10000 40000

The permittee used the Industrial Source Complex Short Term model (ISCST3, Version 99155, EPA, 1999) in the analysis. The ISCST3 model fulfills the requirements of Supplement C of the Guideline on Air Quality Models (Appendix W to 40 CFR 51). All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with the prescribed usage for this model. Per EPA guidance, the ISCST3 model was run with the regulatory default option in a sequential hourly mode using five consecutive years of meteorological data. Surface data and concurrent upper air data used were based on weather observations taken at the National Weather Service (NWS) station at the Paducah, Kentucky airport from 1990 to 1994. Although data for 1995 to 1997 are available, the cloud cover/ceiling height observations obtained through Automated Surface Observation System (ASOS) which became operational in August 1995, are inconsistent with the EPA meteorological processing guidelines for determining atmospheric stability. Thus, this more recent data was not used.

B. Modeling results - Class II Area Impacts

The proposed facility will be located in Marshall County, a Class II area. The permittee modeled the impact of the emissions from the proposed facilities on the ambient air quality and the results of the modeled impacts on the Class II area have been presented in the Table 4.

The modeling results show (Table 4) that the maximum impacts from the proposed facility for NO_x, PM_{10}, SO_2, CO are less than the EPA prescribed significant ambient impact levels (SIL). These concentrations are also below the significant monitoring concentrations (SMC) found in Regulation 401 KAR 51:017, Section 24. Since the maximum predicted impacts for each pollutant are found

to be below the SILs, then it is assumed that the proposed facility will not cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling is required at this time. The applicant is also exempted from the ambient monitoring data requirements since the impacts are shown to be below the SMC.

Table 4

Pollutant	**Averaging Period**	**SIL** ($\mu g/m^3$)	**SMC** ($\mu g/m^3$)	**Max Impact of Emission** ($\mu g/m^3$)
NO_2	Annual	1	14	0.231
PM_{10}	Annual 24-hour	1 5	NA 10	0.068 3.76**
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	0.055 3.64** 11.7
CO	8-hour 1-hour	500 2000	575 NA	22.6 93.2

** 24-hour averages based on 16 hours for turbines during oil firing.

C. Modeling Results - Class I Area Impacts

The nearest federally designated Class I area to the project site is Mingo National Wilderness Area in southeast Missouri. Mingo is 154 km west of the proposed facility the permittee documents. Mammoth Cave, Kentucky is approximately 180 km from the proposed source. Based on the results of the dispersion analysis of the proposed project's emissions, summarized in the application Section 6.0, it is demonstrated by the permittee that the impacts of the Duke Energy Marshall County facility are less than the EPA-instituted Class I significant levels (established through the proposed New Source Review Reform regulations). Thus, the permittee documents that a comprehensive cumulative Class I increment and NAAQS analysis is not required.

The PSD regulations also require a demonstration that the proposed source's emissions would not adversely affect a Class I area's air quality related values (AQRV). Since the proposed source will be located more than 100 km from the nearest Class I area, a Class I AQRV analysis was not required of the permittee.

7. ADDITIONAL IMPACTS ANALYSIS

A. Growth Analysis

The consultant documents the following information for the proposed facility:
The Duke Energy Marshall County project will employ approximately 200 personnel during the construction phase. The project will employ approximately 6 people on a permanent basis. It is a goal of the project to hire from the local community where possible. There should be no substantial increase in community growth, or need for additional infrastructure. The proposed project is also not expected to result in an increase in secondary emissions associated with non-project related activities. Thus, in accordance with PSD guidelines, the analysis of ambient air quality impacts need consider only emissions from the facility itself.

B. Soils and Vegetation Impacts Analysis

The project lies in an area of mainly agricultural use. No significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. The criteria for evaluating impacts on soils and vegetation is taken from EPA's A Screening Procedure for the Impacts of the Air Pollution Sources on Plants, Soils, and Animals (EPA 1980). Table 6-5 on p. 6-11 of the application, compares SO2 sensitive vegetation levels with maximum refined ISCTS3 model impacts from the proposed project. The results demonstrate maximum concentrations are well below sensitive levels. (This comparison includes ambient background levels.) The minimum impact level numbers in micrograms per cubic meters are not exceeded by the maximum impact concentration of the Duke Energy Marshall County project for the pollutants sulfur dioxide, nitrogen dioxide, or carbon monoxide. Therefore, it is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of the proposed project.

C. Visibility Impairment Analysis

On the basis of the insignificant modeling results presented in the application, it is also concluded that the facility will have no adverse impact on local visibility, since the significant impact levels are lower than the secondary NAAQS.

Additionally, the permittee has explained that the nearest Class I area is over 100 km away. Therefore, no further analysis was done for visibility impairment.

8. CONCLUSION AND RECOMMENDATION

In conclusion, considering the information presented in the application, the Division has made a preliminary determination that the proposed source should meet all applicable requirements:

1. All the emissions units are expected to meet the requirements of BACT for each significant pollutant. Additionally, each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63 will also be met.
2. Ambient air quality impacts on Class II areas are expected to be below the significant impact levels. No impact is expected on any Class I area.
3. Impacts on soil, vegetation, and visibility have been predicted to be minimal.

A draft permit containing conditions which may ensure compliance with all the applicable requirements listed above has been prepared by the Division. The Division recommends the issuance of the permit following the public notice period, and after the resolution of any adverse comments received by the Division. A copy of this preliminary determination will be made available for public review at the following locations:

1. Affected public at the Marshall County Clerk's office.
2. Division for Air Quality, 803 Schenkel Lane, Frankfort.
3. Division for Air Quality, Paducah Regional Office, 4500 Clarks River Road, Paducah.